Transmission Pricing Methodology: Avoided cost of transmission (ACOT) payments for distributed generation

A submission to the Electricity Authority

31 January 2014

Trustpower Limited (Trustpower) welcomes the opportunity to provide a submission to the Electricity Authority (Authority) on its *Transmission Pricing Methodology: Avoided cost of transmission (ACOT) payments for distributed generation* working paper (the Working Paper).

To assist us in providing feedback to the Authority, we have commissioned the following two reports, which are appended to, and should be considered part of, this submission:

a) Appendix A contains a short history of transmission prices in New Zealand, prepared by Strata Energy Consulting Limited (Strata report). This report outlines the incentives that have applied to investment in distributed generation (DG) inherent in peak demand charges since the 1930s; and

b) Appendix B contains a report prepared by NERA Economic Consulting which addresses the issue of regulatory risk and transition arrangements in relation to regulatory changes which affect committed investment (NERA report).

Trustpower has also read the report prepared by Andrew Shelley Economic Consulting Limited for the Independent Electricity Generators Association (ASEC report). Our submission contains a number of cross-references to this report.

Trustpower notes that the Working Paper makes certain assumptions about Trustpower's existing DG arrangements, drawing on material the Authority has found in the public domain. Some of the information in the paper is factually incorrect. Trustpower would not like the Authority or any reader of this submission to assume that because we have not commented on this information that it is correct. A number of Trustpower's DG arrangements are commercially sensitive and/or subject to confidentiality undertakings. We have formed the view that correction of the information about our DG arrangements in the Working Paper is not necessary for a "high level" policy discussion. If required by the Authority, we would be happy to provide further information about our specific DG investments, on a confidential basis.

For any questions relating to the material in this submission, please contact:

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Executive summary

The Electricity Authority is consulting on a Transmission Pricing Methodology (TPM) working paper on the Avoided Cost of Transmission (ACOT) payments for distributed generation (DG).

The paper suggests that ACOT payments, as currently structured by 18 of the 29 distributors, are "*not promoting efficient outcomes*" and are therefore "*inconsistent with the Authority's statutory objective*" (para 12.3).

This "*preliminary conclusion*" is based on analysis in the working paper that:

- ACOT-funded DG has a limited impact on transmission and distribution businesses' capacity planning processes, as revealed under documents disclosed under information disclosure requirements administered by the Commerce Commission;
- The case for other benefits of DG, such as competition, reliability and environmental benefits, is not compelling, particularly in the context of a national electricity market; and
- The practical effect of a number of the current ACOT payment schemes in the short term is restricted to the redistribution of interconnection charges amongst distribution companies and directly connected consumers.

As a result, the Authority believes that Schedule 6.4 of the Electricity Industry Participation Code (the Code), which provides the regulatory framework for current ACOT payments, should be reviewed.

A further implication of the Working Paper is that changes to the TPM Guidelines which reduce the levels of ACOT payments, for example, changes which allow distributors to opt out of paying for transmission charges would, in the Authority's eyes, improve efficiency. Therefore arguments by submitters on the Authority's October 2012 TPM Consultation Paper, that the Authority failed to take into account the detrimental effect of its TPM Guideline proposal on DG, can be disregarded.

Trustpower considers such conclusions are premature. In this submission we explain our understanding of the history of transmission pricing as it affects DG. This history describes the range of benefits provided by DG which have resulted in successive decision-makers since the 1950s encouraging DG. These benefits include the deferral of expenditure on transmission and distribution networks and the promotion of competition in local regions. Importantly these benefits accrue over the long term, in a dynamic fashion, and will not be revealed by the type of static analysis presented in the Working Paper. The opportunity to realise these benefits is a key benefit of the current transmission charging allocation methodology.

In particular, Trustpower considers the Authority has power to consider the effects of the DG on regional markets and that doing so is in the long-term interests of consumers. Indeed, the history of DG is in part the history of Trustpower as the company's investment in a collection of DG plant has been a core part of its growth from a local supply company to a vertically-integrated, nationwide market participant.

It is also important to note that, in Trustpower's experience, payments have been made to DG on the basis of their ability to reduce peak demand for at least the past four decades, and the incentives to do so have existed since at least the 1930s. Trustpower contends that significant changes to the pricing methodology which applies to existing DG are therefore not consistent with the efficient operation of the industry, or good regulatory practice, because of the effect such changes would have on the legitimate expectations and interests of DG owners who have made investments in reliance on various regulatory and quasi-regulatory schemes.

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1 Introduction

1.1 Trustpower's interest in the Working Paper

1.1.1 Trustpower is a New Zealand based renewable power generator and multiproduct retailer, headquartered in Tauranga. Trustpower was founded in 1924 as a local power authority, the Tauranga Electric Power Board, and has developed into one of New Zealand's best performing companies in the generation, wholesale and retail trading sectors of the electricity industry.

1.1.2 Most of Trustpower's current power generation capacity in New Zealand is embedded in distribution networks and earns Avoided Cost of Transmission (ACOT) payments. Trustpower therefore has a direct interest in the outcomes of this Working Paper. It also has a long history of practical experience of the various regimes which have operated in New Zealand to encourage distributed generation, as both a generator earning payments for avoided transmission costs and a supply authority making such payments to DG embedded in its network (prior to the sale of its lines business in the late 1990s).

1.1.3 Trustpower's involvement in power generation can be traced back to 1968 when it became the joint owner (with Tauranga District Council) of the Kaimai Hydroelectric Power Scheme. The Trustpower Group now owns and operates 37 hydroelectric power schemes and two wind farms in New Zealand, and a wind farm in South Australia (which is currently being expanded).

1.1.4 Trustpower Ltd is a publicly-listed company, having been listed on the New Zealand Stock Exchange in 1994 (TPW.NZ). Trustpower's shareholders include Infratil Limited (a New Zealand utilities investment company; 50.5% of voting shares), the Tauranga Energy Consumer Trust (a consumer trust for Trustpower customers who reside in Tauranga and the Western Bay of Plenty district; 33.1%), institutional investors and the general public (together 16.3%). The Trustpower Group currently employs approximately 560 staff, has annual New Zealand electricity sales of around 3,500 GWh, and generates revenue of over NZ$750 million per year from assets worth close to NZ$2.2 billion.

1.1.5 Trustpower's generation assets across Australasia have a cumulative installed capacity of 730 MW, and an average annual output of approximately 2,800 GWh. Trustpower is well advanced in the construction of the 270 MW Snowtown Stage 2 wind farm, which (on average) will produce a further 985 GWh per annum.

1.1.6 Trustpower's New Zealand electricity customer base consists of around 222,000 electricity connections, including some of the largest electricity consumers in the country. Trustpower also retails internet and telephone services to over 22,000 customers, and now, following the recent acquisition of Energy Direct (NZ) Ltd, retails gas to approximately 11,000 customers.

1.1.7 Since its establishment in 1994, and in its prior incarnation as the Tauranga Electric Power Board, Trustpower has invested considerably in ensuring the reliability of its generation stations and maximising their ability to operate in periods of peak demand.

1.1.8 Through the 1990s, following its corporatisation, Trustpower expanded rapidly, acquiring many DG stations across the country. The business cases for these investments were based on the company's view that DG results in a reduction in transmission and distribution investment in New Zealand for the long term benefit of consumers, which was appropriately reflected in the relevant pricing methodology.

2 History of DG in New Zealand

2.1 Overview

2.1.1 The history of transmission pricing in New Zealand shows that DG and load management have been used to reduce peak demands, improve load factors, and provide overall benefits to the distribution, transmission and generation systems for many years.

2.1.2 The history also shows that the level of the charge has varied from time to time but the signal itself has been constant. This explains the concerns of industry participants at the prospect of the signal being diluted or removed in varied TPM Guidelines.

2.2 New Zealand has a long history of peak demand charges

2.2.1 The Strata report in Appendix A advises that charging for electricity on the basis of peak demand has been in place in New Zealand since the 1930s (at the latest). This meant that the electricity supply authorities (ESAs) that owned their own generation were able to manage their costs by reducing their peak demand; however, those that did not own generation were not able to do so.

2.2.2 At this time the ESAs were not charged for their energy consumption *per se* – instead the only charge levied on an ESA was based on peak demand. The charge was not based on how much energy was consumed through the year, but on how much was consumed in peak demand periods. Therefore an ESA could reduce its effective charge per kWh consumed by reducing its peak demand, in much the same way as distribution companies today can (and do) reduce their share of transmission charges by reducing their peak demand.

2.2.3 The Bulk Supply Tariff (BST) was introduced in 1953, and still charged only on the basis of peak demand. The BST was not split into a charge for energy consumption (per kWh) as well as peak demand (per kW) until 1967.

2.2.4 The BST was frozen from 1967-1976, which led to the New Zealand Electricity Department operating at a deficit. The peak demand charge was increased significantly over the period 1977-1983 in response. As noted in the Strata report, "*The rapid increase in demand charges for a bulk supply consumer provided an incentive to improve the load factor, i.e. the ratio of the average demand over the year to the maximum demand in the year*" (para 29).

2.2.5 From 1984, the BST was split into four components: winter peak demand, anytime peak demand, day rate energy and night rate energy.

2.2.6 In 1988, the BST was replaced by separate energy and transmission contracts. Between 1988 and the present day, the wholesale electricity market was introduced and the structure of transmission charges was altered significantly, eventually evolving into the charging methodology with which today's participants are familiar. The Strata report divides this into four phases, each of which maintained a demand-based charge.

2.2.7 In 2007 the Minister of Energy approved a TPM which allocated interconnection charges on the basis of off-take customers' regional coincident peak demand. As noted in the Strata report, this charge was designed to give a locational pricing signal for load management and new investment (para 63(b)(i)).

2.2.8 Thus ACOT-type incentives (and, in Trustpower's experience, payments) are not a recent phenomenon. Signals to reduce peak demand (via DG) date back to at least the 1950s, when the NZ BST was levied on local power boards solely on the basis of peak draw from the grid.

2.3 Peak demand charges have been much greater in the past than current levels

2.3.1 Over time, local supply authorities/electricity distribution businesses responded to these incentives to reduce the amount of electricity being consumed by their customers at times of peak demand. This was done through investment in distributed generation and load management capability.

2.3.2 The level of peak demand charges since the 1950s is shown in Figure 1 below, extracted from the Strata report. These charges are shown in nominal dollars (red line) and real (2013) dollars (purple line).

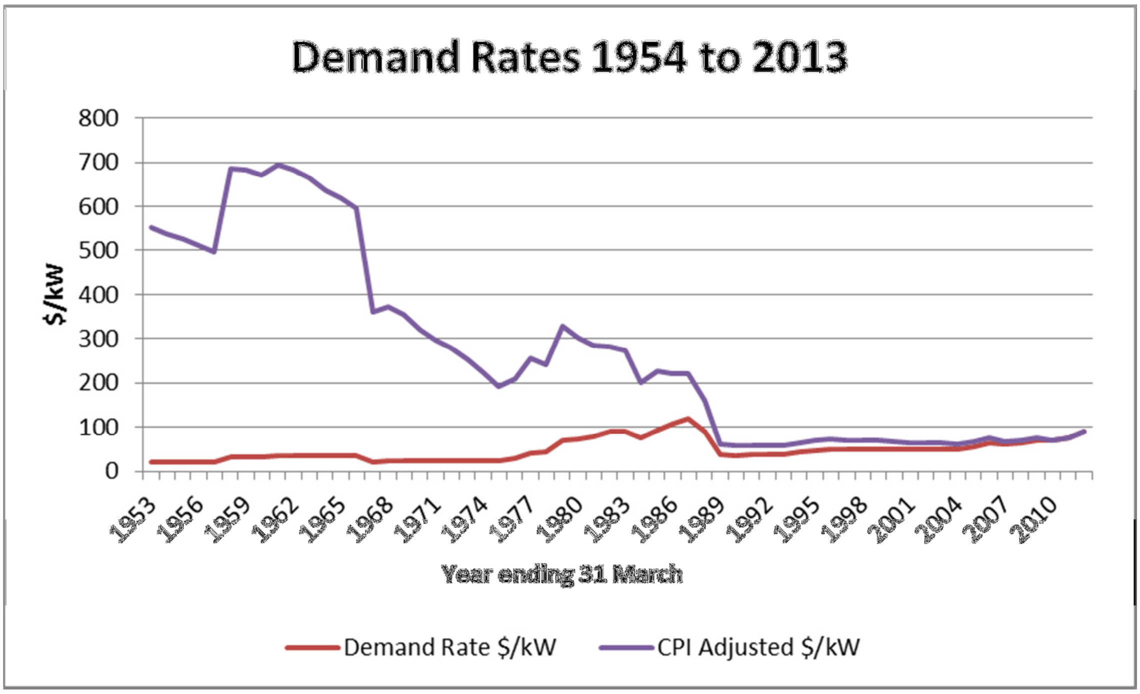

Figure 1: Peak demand charges in New Zealand from 1953-2013

2.3.3 As can be seen in the chart, the level of incentives has varied over time; however, peak charges have traditionally been much higher than current levels.

2.3.4 This data shows that in the period since the introduction of the BST in 1953, the lowest that peak demand charges have been (in 2013 dollars) is $58/kW, in 1991 and again in 1994. The maximum level was $694/kW in 1962.

2.3.5 Trustpower expects that current DG investments have been made taking into account the risk that levels of peak charges may fluctuate, and that it would now be prudent only to expect benefits at the lower bound of the range of $/kw charges that has applied since the 1950s. However, prior to the Working Paper, such investments would not assume that a signal which had been in place for more than sixty years would be abruptly removed.

3 Benefits of DG

3.1 Locational signals provided to DG plant

3.1.1 The Working Paper discusses whether the current ACOT payment arrangements have an impact on the location of plant. It concludes that the location of resources is likely to be a more important factor, particularly in relation to renewable generation.

3.1.2 Trustpower agrees that access to a suitable resource is a key factor in assessing the viability of a particular generation scheme. However, in our experience as a DG investor, the locational signal provided by the existing TPM has also been important when determining the location of new DG.

3.1.3 In particular, the locational signal becomes important when comparing between schemes, and when considering the configuration of a particular scheme. In the case of hydro plant in particular, there are always trade-offs between peaking capacity and energy production, with peaking capacity (backed by storage, to increase reliability) being the most relevant for deferral of transmission investment.

3.1.4 It is also worth noting that while the rate of ACOT payments per kW are fairly consistent across the country, the signal is much stronger in the upper island regions, which signals a much stronger requirement for peak capacity. For example, Trustpower's Bream Bay diesel peaking station was located in the upper North Island in part due to the stronger locational pricing signal provided in that region.

3.1.5 Further, one of the critical components in the design of the prospective new Arnold hydro power scheme on the West Coast was to have enough storage to ensure that all of the region's peak demand periods could be "hit" at maximum output with an extremely high level of confidence, thus reliably deferring the need for future transmission investment into the region.

3.1.6 However, storage comes at a cost, and in the lower regions of both islands the level of storage required to hit the greater number of peaks would be significant. The extra cost incurred in ensuring peaks could be hit in the upper regions, however, would likely be significantly cheaper, on a present value basis, than the extra transmission investment such reliable operation could defer.

3.1.7 We therefore agree with the Authority that, based on our experience, the benefits of DG are enhanced with storage and we are constantly assessing ways in which the storage capacities (and, hence, reliability) of our DG schemes can be enhanced efficiently.

3.2 Signals to DG plant on generation station configuration

3.2.1 ACOT payments have had an important influence on the design and operation of existing DG. This is not discussed in the Working Paper.

3.2.2 The key point is that the configuration of DG which is designed to reliably reduce peak demand and defer transmission investment may be quite different to generation capacity that is unable to do so. Case studies of DG plant show that DG is often configured and operated specifically to accommodate network requirements and ensure it can operate at peak times to reduce transmission charges.

3.2.3 Many of Trustpower's DG schemes would appear, on the surface, to be over-engineered compared to schemes that did not have the requirement to operate reliably at peak. The over-engineering would have incurred greater cost at the time of investment, but would have been justified due to the expected ongoing savings of transmission costs accrued.

3.2.4 Several such case studies of Trustpower's assets are presented in this sub-section. The case studies demonstrate that Trustpower's schemes bring benefits to consumers in the form of reduced transmission expenditure.

Kaimai power scheme

3.2.5 The Kaimai power scheme began with the McLarens Falls Power Station in 1925 (now decommissioned). The original power station was built to supply electricity to the Tauranga area before the national grid extended to the Bay of Plenty.

3.2.6 From the early 1970s, the existing Kaimai hydroelectric scheme was progressively developed with the commissioning of the Lloyd Mandeno Power Station in 1972, followed by Lower Mangapapa and Ruahihi in 1981. A small 300 kW additional station was commissioned in 1994 to utilise the head on a diversion tunnel. An overview of the scheme is shown in Figure 2 below.

3.2.7 A key design criterion of the Kaimai Scheme was to have the capacity to support the local Tauranga electricity demand during peak demand periods and to respond to the peak demand charges imposed by the New Zealand Electricity Department (and, later, Transpower). The scheme was designed to provide firm capacity, and storage reservoirs added to enable additional peak capacity to meet electricity demand peaks. The scheme would not have been designed that way if it was intended to supply energy requirements only.

3.2.8 The design features included:

a) daily storage reservoir to support peaking generation[1];

b) multiple generating units with separate step-up transformers within the Lloyd Mandeno and Ruahihi Power Stations to ensure n-1 reliability during peak demand periods;

c) duplicate transmission lines within the scheme, and three lines between the scheme and the Tauranga load to provide n-1 reliability;

[1] Much of the inflows come from spring-fed sources, and as a result there is sufficient reliability in water supply to ensure that generation can be provided for peaking operation on a reliable basis even with only daily storage.

d) connection into a strong part of the Tauranga distribution network; and

e) ability to run islanded.

3.2.9 Until recently, the Tauranga area had been an import-constrained part of the grid, however the Kaimai Scheme successfully deferred transmission reinforcement into the area for many years. Prior to recent transmission upgrades, the supply to consumers from Transpower's Tauranga substation could not be met at peak times without generation from the Kaimai Scheme.

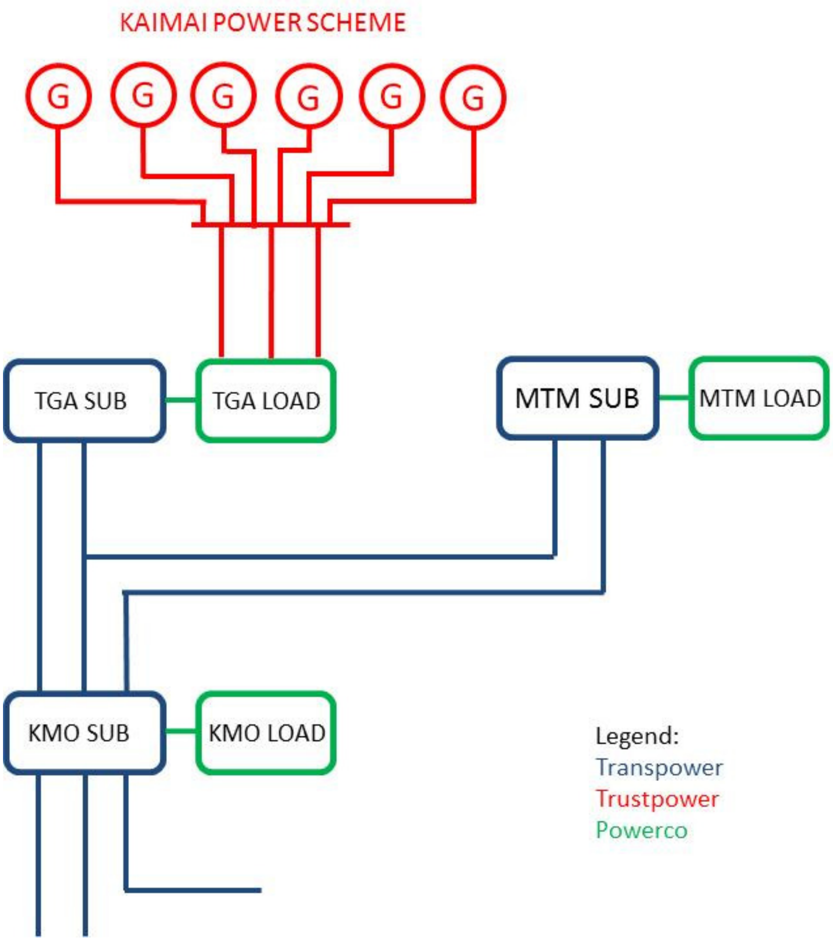

Figure 2: Simple diagram of the Tauranga area power network

Patea power scheme

3.2.10 The Patea power scheme was designed to provide reliable local capacity support with an equivalent reliability to a transmission solution.

3.2.11 The power station has three 10.5 MW generating units with two transformer banks (each capable of 21 MW). With any element out of service, the scheme is able to generate 21 MW at peak demand periods.

3.2.12 As with the Kaimai scheme, Patea was designed to provide reliable generation and would have been designed differently if the purpose was to supply energy only.

Wheao/Flaxy power scheme

3.2.13 The Wheao/Flaxy Scheme was designed around the same time as the Ruahihi power station and was specifically designed with the New Zealand Electricity Department demand charges as a driver. As with Kaimai and Patea, Wheao was designed with multiple units to ensure n-1 reliability, and, in addition, the Flaxy power station and associated reservoir was added to enable water to be stored to meet the daily peak requirements.

3.2.14 The Flaxy reservoir and station would not have been added to the scheme if there was no compensation for providing additional capacity support at peak times rewarded via avoided transmission payments.

West Coast

3.2.15 Trustpower also owns the majority of hydro generation on the West Coast of the South Island. The West Coast Schemes were designed to provide regional capacity, and, through the multiple generation stations and reservoirs, to provide significant transmission support into the region at a time when the demand charges were aggregated over an ESA's entire area but determined in a similar way to the present RCPD methodology. As described in more detail in the ASEC report (section 5.2), the existence of these generation schemes has deferred transmission investment in the region materially.

3.3 Competition benefits

3.3.1 The Working Paper raises but then dismisses the competition benefits provided by DG. Local and competition benefits were identified by the Ministry of Economic Development (MED) in a 2003 discussion paper, and were highlighted by a number of parties in written and oral submissions on the Authority's October 2012 TPM Issues Paper.

3.3.2 The Working Paper appears to accept that there can be local benefits e.g. where a DG plant is established in a constrained region. However, these are then disregarded by the Authority:

> *"The wholesale and retail markets are considered to be national markets. Hence there are not separate regional generation markets and DG competes in the same markets as grid connected generation. It would therefore be inefficient to provide ACOT payments to DGs solely for any competition benefits that would result."* (para 11.11)

3.3.3 In response Trustpower draws the Authority's attention to section 7.3 of the ASEC report in which the author notes that the Commerce Commission's view is that markets need to be defined according to the question at hand.

3.3.4 Trustpower notes the Electricity Commission did not interpret its statutory objective as only requiring a focus on national market benefits. Nor did the MED appear to think there was any limitation on the Electricity Commission's powers with respect to the development and implementation of Schedule 6.4.

3.3.5 Against this background, Trustpower would appreciate further clarification on the basis on which the Authority determined that its analysis of the benefits of DG must be considered in the context of a national market to comply with its statutory mandate.

3.3.6 From our perspective, we think there is real value in the competition provided by DG at both levels – the local transmission-constrained market and the national level.

3.4 Impact on transmission investment

3.4.1 The Working Paper states in para 8.15, "*The bulk of new DGs that have been installed were small fractions of the transmission capacity and often comparable to the rate of local annual demand growth.*"

3.4.2 This shows that demand growth over time has been (and can be) met by small incremental investments in DG, reducing the need for large, lumpy transmission investments to be made that could result in consumers paying for redundant over-capacity for extended periods of time.

3.4.3 This is likely to be efficient in the future as well, as DG can reduce the prospect of excess transmission capacity being built years in advance of potential utilisation. This is particularly useful in today's environment in which future load growth is so uncertain.

3.4.4 Further, given that ACOT payments may roughly approximate the long run marginal cost of transmission, and DG can defer transmission build, it would seem more efficient to increase capacity in small quantities as required rather than front-load costs with large investments.

3.4.5 The ASEC report notes that transmission upgrades can be very costly for some regions such as the West Coast. In such cases, the author notes:

> *"A reasonable and viable alternative is for more DG to be built. Any DG with an element of storage can be used to reduce net demand during periods of constraint, thus reducing the severity of the constraint. A consequence of such DG will also be the ongoing deferral of the*

transmission upgrade- the very existence of the DG will mean that the transmission link will be kept at current capacity (which may be regularly constrained) and not expanded unless there is a very significant increase in load that cannot be met by building further DG. DG is a very real competitor to transmission and in the more remote distribution networks will be used in place of expensive transmission upgrades." (section 7.3.2)

3.4.6 If future DG installations were able to operate reliably at peak (either individually, or, as illustrated in the ASEC report, in combination with a number of other installations), and could be located anywhere, in theory DG investment could avoid all further investment in new transmission capacity.

3.4.7 The Authority claims in para 8.17 that "*the relatively limited number of [transmission] investments within the past 20 years indicates that the placement and commissioning of DG is unlikely to have substantially altered the progression of transmission investment*". However, relatively little grid expansion is exactly what would be expected if DG were deferring the need for transmission investment. If DG did not defer transmission investment, you would expect to see continual investment in transmission to enable increasing demand to be served.

3.4.8 A related point is that in some circumstances, embedded generation enables transmission outages to take place without compromising supply to the customers on those distribution networks.

3.4.9 History also shows that there has always been an explicit link between transmission charges and DG investment incentives. As noted in the ASEC report, it is only the current regulatory environment with respect to Transpower's regulated revenue cap that results in DG being unable to reduce the transmission charges in any particular year. However, as discussed in the following section, DG can clearly reduce Transpower's revenue requirements over time.

3.5 Investment in load management has received similar incentives

3.5.1 The Working Paper does not refer to load control, and the ability of distributors (and other load aggregators) to shift transmission charges onto other network companies by reducing peak demand. DG is essentially negative load, therefore DG and load control should be treated the same. Both defer investment in generation plant and network infrastructure.

3.5.2 As noted in the Strata report, ESAs began installing load control relays on hot water supplies in the 1950s, in response to rationing requirements and to enable reductions in peak demand (and hence, the ESAs' demand charges).

3.5.3 However, this investment continued well after rationing ended. The majority of ripple control plants in New Zealand are under 30 years old, which suggests a strong incentive to control load remains. This has largely been to reduce peak load on distribution networks, both to defer capital expenditure and reduce transmission charges.

3.5.4 The Strata report advises that the peak load reduction from ripple control (in 2006) was approximately 880 MW. As Strata states, "*That investment [in load control] has deferred the generation plant and network infrastructure that would have been required to meet an additional 880MW of load*".

3.6 Relevance of DG history

3.6.1 This history of DG in New Zealand is relevant because it demonstrates the benefits of DG and the background to the current pricing principles in Schedule 6.4.

3.6.2 The history also highlights the type of analysis that is required before any conclusions can be drawn about the contribution of DG to NZ electricity sector (discussed further in section 4) and provides evidence of the signal which DG in NZ has received from successive decision-makers (discussed further in section 5).

4 Analysing the contribution of DG to the electricity sector

4.1 Requirement to analyse the complete evolution of the power system

4.1.1 If the Authority were to review Schedule 6.4, in order for it to justify reducing the rate of ACOT payments it would have to show that the benefit of doing so would outweigh the cost.

4.1.2 The Authority's preliminary conclusion that "*ACOT payments, and the existence of DG, appears to have no observed effect on transmission investments*" (para 1.15) has not been justified on this basis. To do so would require the Authority essentially to trace the evolution of the existing grid, right back to its genesis in the 1880s, and determine how the evolution would have differed (and consumers been worse or better off) in the absence of DG.

4.1.3 As was the case in Tauranga, many distribution networks were not connected to the national grid at all originally, and hence DG provided the only source of power to consumers on those networks. Assuming consumers valued their supply, that DG capacity must undoubtedly have deferred the need for those networks to be connected to the transmission network and reduced the size of the connection capacity that was put in place. Without the DG being there initially, those consumers would have had no power at all until they were connected to the transmission grid.

4.1.4 The Authority's analysis of the impact of DG on transmission costs in the working paper takes a short-term focus. In any particular year, with the transmission system actually in place, it is true that the operation of DG in peak demand periods will only shift Transpower's charges around between various parties.

4.1.5 However, the benefit of DG plays out over the long term, in the form of deferred transmission investment. Over time, DG reduces the need for (or urgency of) increased transmission investment into regions, resulting in transmission investments being deferred or cancelled completely.

4.1.6 This reduction in investment reduces Transpower's revenue requirements over the long run, reducing the transmission charge for all electricity consumers in New Zealand, not just those on networks which contain DG.

4.1.7 The Authority's conclusion that the current ACOT regime (as administered by the majority of distribution companies) has not resulted in any reduction of transmission investment is simplistic as it does not take into account the evolution of the network over time.

4.1.8 Any assessment of the impact that DG has had on New Zealand's transmission system should not be made on a static basis, as DG is likely to have reduced and delayed spend at a number of different points in the past century, with corresponding benefits still being realised by consumers today.

4.1.9 The ASEC report reaches similar conclusion:

> *"The Working Paper does not show that ACOT funded DG has had no effect on transmission capital investment. We would expect to see a list of transmission capital expenditure projects over the period of interest and a specific assessment of each project as to the reason why it has occurred. Some capital investment is, for example, due to replacement of aging assets. We would also expect to see an analysis of areas where DG is prevalent, to determine the quantum of additional transmission that would be required if the DG was not present."* (section 5.1)

4.1.10 An assessment of the impact of DG should consider the region in which the plant is situated. For example, the size of the region in question is material to the discussion on the ability of DG to defer transmission investment. A hypothetical 20 MW hydro station near Auckland could have done little to defer the North Island Grid Upgrade, on its own. Ten such schemes could have. However, a similarly-sized scheme on the West Coast, where load is only a fraction of that in Auckland, would have a material impact on the level of peak net demand requiring service by transmission capacity. Aggregating the analysis to a national level will therefore not be able to identify the extent to which DG has been able to defer transmission investment.

4.1.11 This is why we do not think the Authority's view that DG payments result in a net cost of $10 per annum for each consumer is soundly based.

4.1.12 As discussed above, in order to establish whether or not DG has reduced transmission spend in New Zealand, the Authority would need to analyse the evolution of New Zealand's power system and determine the extent to which all transmission investments ever undertaken (or which could have been undertaken) have been delayed, down-sized or cancelled as a result of DG. This work has not been done.

4.1.13 In order to understand the potential *future* contribution of DG towards reducing future transmission costs in New Zealand, the Authority would need to model the potential future evolution of the grid and assess how it may be different with and without DG. It could then determine how much future transmission investment could be deferred through DG, and therefore what the benefit of DG actually is. This work has also not been done.

4.2 Assessment of current DG investments

4.2.1 New Zealand's current DG portfolio comprises investments small and large, renewable and non-renewable plant, which are located in both export-constrained and net-importing regions. This portfolio is the outcome of the combination of various signals that DG investors have received, and a number of other market factors.

4.2.2 Parts of the Working Paper appear to be directed towards an assessment of whether:

a) the current DG investments should have been made in the light of other industry developments (including the form of Transpower's economic regulation); or

b) the current portfolio meets the Authority's definition of an efficient level of DG.

4.2.3 We are not sure how well that enquiry fits with the Authority's statutory mandate.

4.2.4 Investment in generation (whether DG or grid-connected) is not (presently) subject to a project-by-project regulatory approval process (which would also guarantee revenues received to support the investment made). Instead it is left to market participants to respond to the signals given by the relevant regulatory frameworks.

4.2.5 While an *ex post* assessment of some investment in DG in certain regions (particular net-exporting regions) may lead to the conclusion that the investment was inefficient in terms of deferral of transmission investment, it should be remembered that these investments were made on the basis of the regulatory framework in place at the time.

4.2.6 If the pricing signals had been more refined, the patterns of investment may have been different.

5 The Authority's mandate and objectives

5.1 Current form of ACOT payments

5.1.1 The pricing principles in Schedule 6.4 of the Code recognise the range of competition, reliability and efficiency benefits DG can provide, and also the need to ease the negotiation burden DG might have with lines companies to ensure these benefits can be realised.

5.1.2 The current arrangements were originally formalised by the Electricity Commission, which, as noted in the Working Paper, had additional statutory objectives.

5.1.3 However when the Government considered what should be in the new Code to be administered by the Authority, these arrangements were retained.

5.1.4 The initial Code was a consolidation of a number of existing rules, including (under section 34(1)(a)(v)), the Electricity Governance (Connection of Distributed Generation) Regulations 2007 (DG Regs) from which Schedule 6.4 was drawn[2].

5.1.5 This consolidated Code was put in place under the Ministerial certifying process described in section 36. This process required the Minister to certify that the draft Code complies with the initial content requirements in section 34, and such certification is conclusive evidence of compliance. This process required the Minister to be satisfied that the Code was consistent with the Act.

[2] It is worth noting that payments to DG from distributors for avoided transmission costs, in their current form, pre-date the DG Regs 2007 by a significant period. Distributors have been making payments to Trustpower's DG stations on the basis of avoided peak charges since these stations were purchased from the ESAs. Indeed, the requirement to make such payments to Trustpower was an indirect condition of the sale and purchase agreements for these stations between Trustpower and the ESAs. Further, when Trustpower (and its previous incarnation, the TEPB), owned and operated the Tauranga lines network, it also made payments to local DG for operating during peak demand periods.

5.1.6 This suggests the Government considered the pricing principles in Schedule 6.4 were consistent with the Authority's statutory objective. Trustpower would agree.

5.2 Amendments to TPM Guidelines and Schedule 6.4

5.2.1 The Authority's power to change the Code is set out in section 32(1) of the Act, which enables Code changes necessary or desirable to promote competition, reliable supply or the efficient operation of the industry, subject to the usual administrative law constraints.

5.2.2 Although the word "industry" is used in section 32(1) we do not interpret this as meaning that the Authority cannot make code changes which only affect a particular node or region. Indeed we think it is core to the Authority's market-enabling role that it is able to make such changes.

5.2.3 The Working Paper does not indicate whether the Authority thinks changes to the ACOT payments are necessary or desirable to promote industry competition, or ensure reliability, or improve the operational efficiency of the industry (or some combination of the above).

5.2.4 Instead, the Authority appears to be of the view that it can remove the pricing principles in the Code if it considers they promote "*inefficient outcomes*".

5.2.5 Trustpower does not think this is a correct interpretation of the Authority's powers. Code changes must fall within one or more of the limbs in section 32(1).

5.2.6 The Authority has suggested the competition and reliability benefits of DG should be disregarded in the context of a national market.

5.2.7 We therefore assume the Authority considers that changes to the ACOT arrangements would enhance the efficient operation of the industry. We discuss this issue in the context of investor certainty below in section 5.3.

5.2.8 We should point out that we think there is a distinction between Code changes which are necessary or desirable to promote the efficient operation of the industry and Code changes which are necessary or desirable to promote efficient investment.

5.2.9 Putting that issue to one side, for the reasons outlined in this submission we struggle to see how a Code change which reduces or removes ACOT payments for existing DG would enhance any efficiency objective.

5.2.10 We draw the Authority's attention to para 3.2 of the NERA report which states:

> *"An amendment to Schedule 6.4 of the Code that reduces or removes ACOT payments would have the effect of reducing the return on investments in distributed generation. Such a change would inevitably reduce the incentive for new distributed generation and, in the first instance, reduce the incentive for existing distributed generators to produce power during periods of peak demand. The effect on requirements for transmission and distribution investment could be material.*
>
> *The amendment would also result in a substantial transfer of wealth from existing investors in distributed generators to other industry participants."*

5.2.11 With regard to wealth transfers, the Authority stated recently in its publication *The Economics of Electricity*[3] that:

> *"Regulators are always able to transfer wealth, but if they do so it has to recognise there will be a cost. The cost will be in the willingness and terms on which parties will invest in generation capacity in the future and in other sectors of the economy."* (para 63)

5.3 Investor expectations

5.3.1 Investments encompassing the development of new DG, and the acquisition and/or enhancement of existing DG have been made on the basis of peak demand charges that have been set and approved by successive governments, regulators and lines companies.

[3] Available online at http://www.ea.govt.nz/dmsdocument/15066

5.3.2 This investment (including cogeneration investment) was made on the basis of forecast returns over the lifetime of assets, which derived from the expectations raised at the time investments were made. The whole purpose of these peak demand price signals was to encourage the desired up-front capital investment by offering increased certainty about the returns which would be available over the life of that investment.

5.3.3 Many of these assets, particularly hydro stations, have very long lives. Some of the DG stations Trustpower owns, such as Waipori, are over 100 years old[4]. Despite *asset* lifetimes being at least 100 years, business cases for investment in hydro stations today generally assume *economic* lifetimes of 70 years (two consent periods) – therefore even a station built in 1980 may only be halfway through its assumed economic lifetime.

5.3.4 The assumption likely to have been made at the time these investments were made was that, for the regulated pricing signals to be effective, the regulator would ensure that payments for reducing peak demand would continue for the duration of this period.

5.3.5 Boards of ESAs and, later, public and private generation companies such as Trustpower, have signed off on investment cases based on these expectations. As discussed above, this expectation was based on both their understanding of the relevant schemes and the longevity of the signals in the NZ context.

5.3.6 As noted earlier, in many cases plant was "over engineered" from what was required for energy supply so that it would have the capacity and reliability to reduce peaks. Trustpower's case studies confirm the ASEC report comment that:

> *"It is reasonable to infer that there was an expectation that peak charges would continue into the indefinite future, and the cost of the over-engineering was always intended to be recovered from those avoided charges rather than the energy charges."* (section 4.5)

5.3.7 The financial impact of changing existing DG arrangements is not trivial. ACOT revenue is a significant portion of the revenues received by some DG plant. Removing ACOT will create significant wealth transfers between industry participants, and have an adverse impact on smaller market participants. This will exacerbate concerns about regulatory predictability and stability.

5.3.8 As discussed in the NERA report, increases in the perception of regulatory risk will increase the cost of capital of all potential investors in the market. This will in turn increase hurdle rates, delay investment and increase energy prices to consumers. Markets are already concerned about the New Zealand regulatory environment, with a recent example being the downgrade of Vector's credit rating.

5.3.9 Removing the ACOT regime will also reduce the effectiveness of future regulated signalling. As noted in the NERA report, participants will become more wary of the potential for the regulator to change signals, and future signals will have to be strengthened above efficient levels in order to stimulate the actions required.

5.3.10 The ASEC report further comments:

> *"Any decisions to invest now or in the near term will have to take account of the possibility that an expected income stream may be eliminated by regulatory fiat in future. This will have a chilling effect on investment, thereby harming the long term interests of consumers."* (section 4.5)

5.3.11 This does not appear consistent with the efficient operation of the industry.

6 Administrative law principles

6.1.1 We also note that the Authority's powers may be constrained by the administrative law presumptions against delegated legislation having retrospective effect.

6.1.2 As noted earlier, New Zealand has had longstanding arrangements to encourage DG. These arrangements were developed to give DG owners increased certainty about the payback of their investment. This in

[4] It is worth noting as an aside that hydro asset lifetimes (especially the civil structures) are significantly longer than those of transmission assets.

turn was based on the benefits provided by DG over time in relation to the network. In return, DG owners made the desired up-front capital investments. Thus it could be argued that the arrangements amount to a prospective scheme which confers interests on DG owners which have already vested.

6.1.3 This interpretation would constrain the Authority from amending the price signals which apply to existing DG that might be put in place after any future Code changes.

6.1.4 This potential legal constraint, as well as the history of DG, suggests that in New Zealand the regulatory frameworks for transmission charging and DG payments are strongly interlinked. It follows that they should be considered together in any review by the Authority.

6.2 Best practice regulation

6.2.1 Trustpower has also considered whether changes which affect electricity sector investment decision-making in the manner proposed are consistent with best practice regulation. We asked NERA to assist us in this analysis.

The NERA report highlights the impact that regulatory decision-making has on investment and operational decision-making by participants in capital-intensive industries. As NERA states, regulatory decisions can "*substantially affect the revenue that can be expected to accrue from capital invested at each and every element of the supply chain.*" (para 3.1)

6.2.2 It follows that:

> *"The long term interests of customers will be best served by regulators acting so as to minimise regulatory risk and uncertainty associated with returns to capital. Investing in infrastructure involves substantial upfront investments and uncertain future revenues."* (para 3.1.2.2)

6.2.3 The NERA report highlights the core principles which should be applied by regulators to take into account the interests of investors when making and amending rules that affect returns to invested capital.

6.2.4 These principles include:

a) The principle of **cost recovery**, which would enable investors to have a reasonable opportunity to recover the cost of their investment – including an appropriate return on that investment; and

b) The principle that the regulator should seek to **minimise perceptions of regulatory risk**, for example by making decisions that specifically reduce the risk of unanticipated change.

6.2.5 NERA suggests that the Authority has regard to these principles when discharging its statutory functions, and explains why this is consistent with the Authority's statutory objective:

> *"The principle of cost recovery is consistent with the Authority's statutory objective of promoting competition in, reliable supply by, and the efficient operation of, the electricity industry for the long term benefit of consumers.*
>
> *A reasonable prospect of cost recovery is a necessary precondition for efficient private sector investment in the electricity industry. It therefore underpins the delivery of reliable supply which is in the long term interests of consumers."* (para 3.1.1)

6.2.6 Best practice regulation is also discussed in the ASEC report, in which the author refers to the New Zealand Treasury Best Practice Regulation Framework and observes:

"One attribute of Best Practice Regulation is that it is "certain and predictable", with the regulatory regime being predictable over time. Both that attribute and the "growth supporting" attribute include an indicator that requires the need for firms to take long term investment decisions to be taken into account. The potential removal of ACOT, whether directly or by way of major changes to the transmission pricing methodology, is not consistent with these indicators, as investment decisions have been made with the expectation of some form of continuing ACOT payment. Eliminating these payments will adversely affect investment incentives." (section 3.3)

7 Transitional arrangements

7.1.1 The Working Paper also notes, in its executive summary, that the Authority might put in place transitional arrangements if it reviews the Part 6 pricing principles. Trustpower therefore asked NERA to comment on the extent to which it might be necessary to put in place such arrangements if the Authority decided to amend the existing ACOT regime. We asked them to comment from the perspective of best practice.

7.1.2 NERA has concluded that it would only be consistent with the Authority's statutory objective if such arrangements **are** included. They are necessary to mitigate the adverse effects such a change would have on perceptions of increased regulatory risk, and to assist in investor cost recovery.

7.1.3 The NERA report provides a number of different examples of transitional arrangements which regulators have developed in Australia and the United Kingdom to mitigate the effect of changes on existing investors. These include arrangements which entirely exclude, compensate, or cap costs for existing investors, and arrangements which extend compliance timeframes.

7.1.4 In some cases, it was decided that the regulator did not have the power to make changes which affect existing investors.

7.1.5 NERA also considers the United States environment, which has a particularly long history of economic regulation and direct experience of the regulatory risk which occurs when the regulatory compact between regulators and investors breaks down. As a result, the United States has now developed various arrangements in both its regulatory practice and case law which support the property rights of investors who have made investments in response to a public need.

7.1.6 These principles and arrangements should be taken into account by the Authority if it proposes to amend the ACOT arrangements.

7.1.7 Given the history of DG investment in New Zealand, we believe the optimal approach, and one consistent with the best-practice principles and arrangements discussed in the NERA report, would be for the Authority to provide for separate treatment between existing DG and that DG which is committed for construction after the completion of any review of Schedule 6.4. New DG would be remunerated under the new regime, however the Authority should ensure that ACOT payments continue to be made to existing DG at levels consistent (in real terms) with those received in recent history.

8 Concluding remarks

8.1.1 As the TPM Guidelines and the pricing principles in Schedule 6.4 are intended to provide an enduring methodology, the Authority should require a strong case to be made to make a structural change to the TPM Guidelines and Schedule 6.4 which will harm a type of investment previous decision-makers have actively encouraged. Self-evidently, such changes will be very difficult to reverse.

8.1.2 The Working Paper sets out the Authority's case for change. In response, our submission has noted:

a) New Zealand has a long history of offering incentives to encourage investments which reduce transmission peaks. Transmission charging arrangements and payments to DG for reducing peak demand are interlinked, and practically always have been. This history extends considerably further back in time than the DG Regs referred to in the Working Paper.

b) Investments in DG and load management have been made in response to these longstanding signals.

c) The level of the incentive has fluctuated over time, with current levels near the lower bounds of the long-term range. However, the signal itself has been in existence for more than sixty years.

d) Contrary to the paper's conclusions, some of the Authority's analysis suggests that DG has been effective in deferring transmission investment. Other parts of the analysis have been conducted at too high a level to throw any light on the impact DG has had on transmission investment over the last 100 years.

e) In addition to its role in deferring transmission investment, DG provides a number of other benefits to the industry. These are largely overlooked in the Authority's analysis.

f) In order to fully assess the scope, extent and value of all the benefits DG provides to the industry the Authority would need to undertake a different kind of analysis to that included in the working paper, which recognises the long-term nature of the benefits in the evolution of the power system.

g) The pricing arrangements developed by the Electricity Commission have been included in the Code administered by the Authority, suggesting they are consistent with the Authority's objectives.

h) Changes to these arrangements would need to fall within one of the limbs in section 32(1) and comply with administrative law principles.

i) The expectations of current DG investors mean that it would not be consistent with the efficient operation of the industry for the Authority to amend the pricing principles which apply to their existing DG investments. Such a change would also not be consistent with our understanding of best-practice regulation.

j) Further analysis of the kind described in this submission would be needed to determine if these principles need to be refined in respect of new DG.

8.1.3 However at this stage the Authority's conclusions on the limited economic benefits of DG, and its view that that the current arrangements are inconsistent with its statutory objective, appear premature.

Appendix A: Strata Energy Consulting Report

Strata Energy Consulting Limited (2014). *Report on the history of the Bulk Supply Tariff and Transmission Pricing in New Zealand***.** A report for Trustpower Limited.

Appendix B: NERA Economic Consulting Report

NERA Economic Consulting (2014). *Regulatory Change Management*. A report for Trustpower Limited.